Deutsches Institut für
Wirtschaftsforschung

DIW BERLIN

Discussion Papers

1028

Tarjei Kristiansen • Juan Rosellon

Merchant Electricity Transmission Expansion: A European Case Study

Berlin, July 2010

IMPRESSUM

DIW Berlin
German Institute for Economic Research
Mohrenstr. 58
10117 Berlin
Tel. +49 (30) 897 89-0
Fax +49 (30) 897 89-200
http://www.diw.de

ISSN print edition 1433-0210
ISSN electronic edition 1619-4535

Available for free downloading from the DIW Berlin website.

Discussion Papers of DIW Berlin are indexed in RePEc and SSRN.
Papers can be downloaded free of charge from the following websites:

http://www.diw.de/de/diw_01.c.100406.de/publikationen_veranstaltungen/publikationen/diskussionspapiere/diskussionspapiere.html
http://ideas.repec.org/s/diw/diwwpp.html
http://papers.ssrn.com/sol3/JELJOUR_Results.cfm?form_name=journalbrowse&journal_id=1079991

Merchant Electricity Transmission Expansion: A European Case Study

Tarjei Kristiansen [*]

Juan Rosellón [¥]

Abstract

We apply a merchant transmission model to the trilateral market coupling (TLC) arrangement among the Netherlands, Belgium and France as a generic example, and note that it can be applied to any general market splitting or coupling of Europe's different national power markets. In this merchant framework; the system operator allocates financial transmission rights (FTRs) to investors in transmission expansion based upon their preferences, and revenue adequacy. The independent system operator (ISO) preserves some proxy FTRs to deal with potential negative externalities due to an expansion project. This scheme proves to be capable in providing incentives for investment in transmission expansion projects within TLC areas.

Keywords: transmission expansion, trilateral market coupling, Europe, financial transmission rights, congestion management

JEL classification: L51, L91, L94, Q40

[*] RBS Sempra Commodities
155 Bishopsgate, London EC2M3TZ, UK
Email: tarjei_kristiansen_2003@alumni.ksg.harvard.edu

[¥] Centro de Investigación y Docencia Económicas (CIDE) and German Institute for Economic Research (DIW-Berlin)
División de Economía, Carretera México-Toluca 3655, Lomas de Santa Fé, 01210, México D.F. MEXICO
Email: juan.rosellon@cide.edu

1. Introduction

In this paper we study the case for FTRs in Europe including incentives for investors in transmission expansion. We apply a merchant transmission expansion model to the trilateral market coupling (TLC) arrangement among the Netherlands, Belgium and France as a generic example. We note that our merchant transmission mechanism may also be applied to any general market splitting or coupling of Europe's different national power markets. Within a merchant framework, the system operator allocates financial transmission rights (FTRs) to investors in transmission expansion based upon their preferences for transmission capacity and revenue adequacy. To maintain the credit standing of the system operator -who is the counterparty of investors- the revenue collected from locational prices differences in the dispatch should at least be equal to the payments to the holders of FTRs in the same period (revenue adequacy). When the set of FTRs satisfy the simultaneous feasibility conditions that are governed by the transmission system constraints revenue adequacy follows (see Hogan, 2002b). In our framework, the ISO preserves some proxy FTRs to deal with potential negative externalities due to an expansion project.

The FTR analysis is of static nature since it assumes a fixed transmission network for a certain period. The dynamics of the network can be considered by taking into account future changes, and running the simultaneous feasibility test for these periods. However, transmission investments are dynamic, and there is no perfect coordination of interdependent investments in generation and transmission. Supply and demand are stochastic and therefore locational prices are stochastic.

Prior to November 21, 2006, the cross-border trade among the Netherlands, Belgium and France was managed by explicit auctions. Now, the daily auctions accommodate a TLC arrangement (an implicit auction) that has resulted in more efficient trade and a single price for most time periods (APX, 2007). The highest volume in MWh is traded in the spot market (80%) followed by annual (13%) and monthly auctions (6%). However, annual and monthly transmission allocations still utilize explicit auctions. The three exchanges, Powernext, Belpex and APX, operate the market coupling which determines the market prices. The TLC links the offers and demands of the three power exchanges in their areas via an algorithm that calculates imports and exports (APX, 2007). The three transmission system operators (TSOs), RTE (Réseau de Transport d'Electricité), ELIA (Elia System Operator SA) and TenneT (TenneT B.V), remain responsible for calculating and publishing capacity, and the cross-border flows. Decoupling from the TLC arrangement of the three areas is also possible, in which case explicit auctions are then utilized.

Recent discussion in Europe has focused on introducing FTRs as a component of the TLC, and moving to flow-based transmission and open/multilateral market coupling. The allocation of cross-border capacity is currently based on net transfer capacity (NTC).[1] For a flow-based allocation mechanism, all regional commercial transactions would be converted into physical power flows at the critical tie-lines[2] or individual lines on the

[1] See appendix for details.
[2] Aggregated lines per border.

border by using the power transfer distribution factors (PTDFs). Thus, PTDFs and line constraints would substitute for the NTCs in the flow calculations. The PTDFs would account for physical electrical flow paths, and maximize the use of transmission capacity subject to line constraints. A meshed network would make it more difficult to link the implicit and explicit auctions employed in the daily, monthly, and annual auctions respectively.

In this paper we discuss how the FTR model for transmission expansion can be introduced in the TLC arrangement. The plan of the paper is as follows: section 2 presents the use of flow-based methods to resolve transmission congestion in Europe. In section 3 we analyze several recent results of TLC arrangements. Some discussion concerning the use of merchant mechanisms to resolve transmission expansion appears in section 4. The application of our FTR model to the proposed European network is developed in section 5. The implied welfare analysis is presented in section 6 followed by our concluding remarks.

2. Market coupling and flow-based congestion management methods in Europe

We first start with defining some important concepts in flow-based congestion management. ETSO (2007) defined a border capacity (BC) concept. CONSENTEC and APCS (2008) extended and replaced this concept with an advanced concept of flow-based capacity model, "MF approach", from the beginning of 2008 (see Table 1). The BC concept applies to tie lines (collection of lines) as compared to the MF approach which refers to individual lines. In contrast to these approaches, some European markets currently use market splitting/coupling with a net transfer capacity (NTC) approach which only considers a bilateral exchange program, and no simultaneous network interactions. We refer in the following to a general description of flow-based allocation which can be applied to the both the BC and the MF concept.

Differences	Border capacity (BC)	Maximum flow (MF)
Constraints	Allocation is constrained by the flow on tie lines, aggregated per border	Allocation is constrained by the flow on individual lines/transformers
Structure	Two constraints per border (one per direction)	Two constraints per critical branch and topology
Consideration of network security	Most critical outage topology for each border is estimated at time of capacity allocation. Details are only known to single TSO.	All potentially critically outage topologies are constrained in the model. Most critical one is determined at time of allocation.

Table 1. Comparison of the border capacity (BC) and maximum flow (MF) concepts.

Flow Based Congestion Management

A flow based congestion management method considers the real power flow paths (through) PTDFs determined by transactions and physical capacity limits. In market coupling, players submit bids for their energy production/consumption consisting of corresponding price and volume while the daily cross-border transmission capacity between the various areas is implicitly made available via energy transactions on the power exchanges on either side of the border.In coordinated explicit auctions, players submit bids for transmission capacity prices. The flow-based congestion management methods would support FTRs because these can be transformed to flows (via the PTDFs). The allocation is then restricted by flows (not by the amount of exchange), and the amount of FTRs between two areas is a result of the allocation. The PTDFs describe the amount of physical flow on a given branch) (with branch meaning either aggregated lines or individual lines) that would be provoked by a requested commercial exchange between two countries or two control areas (or ‘hubs’). The two hubs do not necessarily need to be directly connected. In flow-based allocation, NTCs do not exist between two control areas. However, the maximum allowable flow and an estimate of the flow that is already present on certain branches are available prior to the allocation. The commercial transactions are no longer limited to the cross-borders where they are reported, but they are converted into physical power flows by using a simplified representation of the network so that their impacts on third interconnections can be considered (thus ensuring overall security). ´The flow-based transmission capacity allocation can be viewed as a supra-national approach because one centralized auction administrator optimizes and allocates all of the energy price bids and/or cross-border capacity bids.

In the implicit flow-based allocation, the influence of all price area imbalances is totaled for each critical branch. When the resulting physical flow is higher than what is available on a certain critical branch (i.e. the maximum allowed flow minus the flow that is already present prior to the allocation), the energy bid/offer with the lowest negative impact on the objective function will be reduced first.

The explicit flow-based allocation procedure does not aim to reduce the differences between physical flows and commercial exchanges on a given critical tie or individual line between two countries or two control areas. Physical flows determine how price area imbalances define a certain commercial exchange amongst the infinite possible number of possible commercial exchanges. Thus, the ‘flow-based’ allocation method may not necessarily reduce the difference between commercial exchanges and physical flows on tie or individual lines between control areas. However, this method does provide the means to allocate capacity to the bids valuing it the highest in a given region subject to transmission capacity limits.

We note that another criterion is needed to define a unique set among the infinity of possible sets of cross-border commercial exchanges translating the price area imbalances. This optimization problem can be solved as a linear program for which the simplified ‘mathematical’ description is as follows (ETSO, 2007):

a) for an explicit flow-based allocation

$$\max \sum_i p_i q_i$$
$$0 \le q_i \le Q$$
$$PTDF \cdot q_i \le (F_{\max} - F_{ref})$$

p_i: bid price

q_i: allocated bid quantity

Q: bid quantity

Fmax: maximum flow

Fref: reference flow

control variable: allocated quantity

b) for an implicit flow-based allocation:

$$\max \sum_i b_i q_{bi} - o_i q_{oi}$$
$$0 \le q_{bi}$$
$$0 \le q_{oi}$$
$$PTDF \cdot q_i \le (F_{\max} - F_{ref})$$
$$q_i = (q_{bi} - q_{oi})$$

b_i: bid price

o_i: offer price

q_{bi}: allocated bid quantity

q_{oi}: allocated offer quantity

q_i: control variable-price area imbalance

The shadow price in the mathematical program allows us to compute the marginal settlement prices.

Although there are no flow-based allocation operations in Europe, there is a dry-run implementation in the region of Central Eastern Europe (CEE) and a dry-run of coordinated auctions in the region of South Eastern Europe (SEE). A flow-based allocation mechanism is under development in the Central-Western European (CWE) region. When implicit auctions are introduced, the market design will be much like that of locational pricing where the nodes are individual countries. A refined model with several nodes per country could also be considered.

The chosen congestion management method must be analyzed in an economic and policy terms. ETSO (2007) discusses some of these issues before implementing a solution. The first issue is market transparency. In an NTC-based allocation mechanism, market players observe the NTC and submit their bids for capacity. When a flow-based transmission model is used for regional capacity allocation, the market players will themselves choose the most economically efficient cross-border trades. Thus, the flow-based method will reveal, in a transparent way, the location of the limiting constraint. Secondly, there must be economic signals to market participants and rules for the sharing of congestion income. Generally all bids in a coordinated flow-based allocation method compete with each other. Thus, low-priced bids between two uncongested control areas have to compete with the high-priced bids between two congested control areas according to their contribution to the congestion. Thirdly, the liabilities of TSOs and position of individual regulatory authorities must be considered. Any commercial transaction may use transmission capacity on each interconnection of the interconnected system. To avoid that any TSO offers no (or very limited) capacity--and thus blocks other transactions-- there should be appropriate revenue distribution methods among TSOs and proper political, regulatory, and TSO coordination.

3. TLC results

The TLC arrangement for the Netherlands, Belgium and France began operations on November 21, 2006. An analysis of the preliminary results already reveals several benefits (Powernext, 2008):

- Optimized use of cross-border transmission capacity among the three countries that supports increased imports and exports.
- Increasing liquidity on Belpex which supports a stable price formation for the Belgian market
- Generally, increased price convergence and price stability (the three markets showed a common price 63% of the time in 2007)

The arrangement has thus resulted in a more optimal and economic utilization of transmission capacity. Table 2 shows the development of the average annual prices before and after the TLC arrangement.[3]

Country price (EUR/MWh)	**Netherlands (APX)**	**France (Powernext)**	**Belgium (Belpex)**
2004	31.35	28.14	NA
2005	52.30	46.73	NA
2006	58.13	49.36	45.69
2007	41.91	40.87	41.8

Table 2. Average annual TLC country prices in different years.

The prices at APX were on average higher than the prices at Powernext before the introduction of the TLC, while the Belpex price was introduced simultaneously with the TLC arrangement (see Figure 1). After the introduction of the TLC, the prices at APX and Powernext had a high correlation and all prices showed high integration.[4] The price levels in the different countries can be explained by the fuel mix, and development of fuel prices during the different years. France has mainly nuclear and hydro power generation. In high peak load hours prices may be set by fuel oil plants with a high marginal cost. French power prices also show a strong correlation with German prices because of substantial exports/imports between these countries. The Netherlands has mainly gas and coal power generation, and a major part of it is co-generation while Belgium has primarily nuclear, gas and hydro power generation. Because the Dutch market has relatively much gas fired and inflexible generation power prices are generally higher than in the other TLC countries. The Belgian market is relatively small compared to the French and Dutch markets, and is thus more like a transit market. From 2004 to 2007, fuel prices in Belgium were generally increasing year on year. However, a sharp drop in the allowance price occurred in May 2006 after the market was long on allowances.

It is relevant to note that even if average prices are similar among the TLC countries, the prices in certain hours may have a large differential and thus contribute to the optionality value of an interconnector. Trading over the interconnector has value in explicit auctions while the payoff is zero in implicit auctions since the transmission price equals the area price differential. In explicit auctions, the cross-border capacity auction price may differ

[3] The TLC arrangement was operated in decoupled mode on April 27 and 28, 2007, when market coupling could not be run/produce correct results, and the day-ahead cross-border capacity was allocated by an explicit auction for the Dutch-Belgium and Belgium-France borders on the same days.

[4] In late April 2007, there were periods when prices at APX and Powernext were higher than at Belpex.

from the realized day-ahead price and the price of transmission capacity is based on market players forecasts of day-ahead prices. In the daily auctions, a market player can purchase capacity and not utilize it if the spot prices indicate that the transaction is unprofitable (optionality).

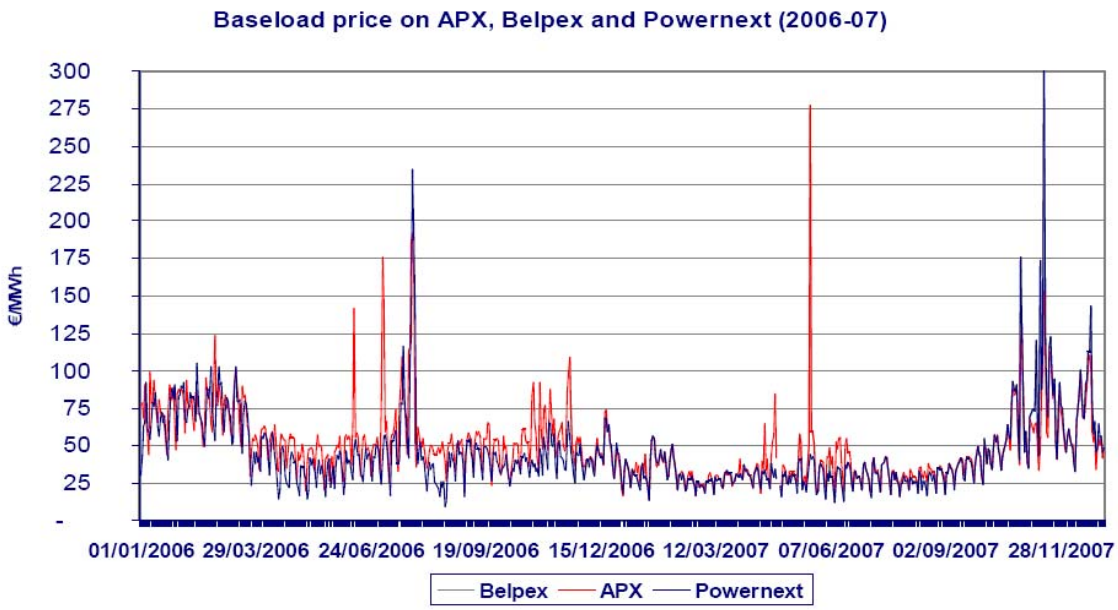

Figure 1. The daily average price for Belpex, APX and Powernext (source: Powernext, 2008).

The annual explicit auctions provide us with information that reveals how market players value cross-border transmission capacity on an annual basis. The prices for 2007 are shown in Table 3. We observe that the TLC countries place the highest value on transmission capacity between Belgium and the Netherlands followed by France to Belgium. Thus it appears that the market players desire capacity from relatively lower-priced France to the relatively higher-priced Netherlands. We can observe the same trend when the market players place the highest value on cross-border capacity from Germany to the Netherlands. The realized annual average day-ahead prices in Table 2 show the same pattern with the largest spread between France and the Netherlands. The spread between Belgium and France is relatively small because of its role as a transit market. It appears that market players bid for transmission capacity based on historic day-ahead prices which in turn is the basis for the forward prices. The market players also have the opportunity to put a bid for transmission capacity based on the forward prices at the time when the auction occurs. Then they can lock in and hedge their profit immediately without much risk.

Cross-border capacity price (€/MWh)	Year 2007 forward direction	Year 2007 backward direction
Netherlands-to- Belgium	0.11	3.46
Belgium-to-France	0.25	2.06
RTE TSO area-to-Netherlands	8.01	0.05
E.ON TSO area-to-Netherlands	8.32	0.03

Table 3. Prices of cross-border capacity in explicit auctions in the TLC countries and in Germany.

We now discuss some of the proposed interconnector projects. Most of them are related to the Netherlands but there have also been transformer projects in Belgium that have helped expanding transmission utilization. Because the Netherlands traditionally has been a higher priced country (especially during peak hours) relative to its neighbors it has been attractive to undertake projects. From a security of supply view it would be of course important to have more interconnectors linking diverse markets together. Two new and two future interconnectors to and from the Netherlands will expand the possibilities for Europe's market players:

- E.ON Netz increased the interconnection capacity from Germany to the Netherlands by 550 MW (from 850 MW to 1400 MW) in October 2007. This capacity could be temporarily limited and initially offered on a non-firm basis during periods of increased wind power generation.
- The 700 MW NorNed cable between Norway and the Netherlands is fully operational since the beginning of May 2008.
- The 1000 MW BritNed cable between the Netherlands and the UK is expected to be fully operational after 2010.
- The German TSO RWE Transportnetz and the Dutch TSO TenneT signed an MoU regarding a new interconnector between their respective TSO areas that will increase transmission from the present 1000 MW to 2000 MW. It is expected to be fully operational by 2013 at the earliest

One motivation for expanding the German-Dutch capacity is Germany increasing share of wind which can be exported (although there may be limitations in high wind periods).

The major motivation for constructing the NorNed cable is security of supply, since Norway is almost entirely dependent (99%) on hydro generation, and the Netherlands is predominantly thermal. In a normal hydrology year, Norway could export peak load power to the Netherlands, or conversely it could import off-peak power from the Netherlands which has lower off-peak prices due to a relative large share of combined heat and power generation (CHP), and must-run generation. In a dry year, Norway could import relatively more power. Norway's abundant hydro generation also provides greater flexibility including the provision of ancillary services. The BritNed project has been undertaken because of security of supply issues and the European Commission's desire to better link the European electricity markets.

4. Merchant transmission investment in Europe

European transmission capacity investments are generally undertaken by the TSOs under the supervision of their national regulators. Approval of the investments in the rate base for regulated transport tariffs requires that these are socially beneficial (Hakvoort and De Jong, 2007). Additionally, the TSOs should utilize revenues from transmission capacity allocation to reinvest in transmission expansion.

EU law allows for commercial transmission investment (merchant investment) by parties other than the TSOs. The investment costs can only be recovered through the price differences on either side of the interconnector. Article 6 of Regulation EC 1228/2003 provides the rules for scarce capacity on existing cross-border interconnectors, Article 7 allows for new interconnectors to be exempted from regulation of the revenues of allocation of scarce capacity, and Articles 20 and 23 require (regulated) third-party access to the network (see Brunekreeft, 2003).

In other words, the EU regulation allows merchant transmission investment, provided a set of conditions is met. The following conditions are the most significant:

- A new interconnector must enhance competition in the energy market.
- Following the unbundling requirements in the EU electricity directive, the interconnector should be legally unbundled from the TSOs linked by it, but ownership separation is not required.
- The exemption to merchant transmission normally applies to direct current (DC) lines, but exceptions are made for alternating current (AC) lines if the cost of DC technology is prohibitive (Brunekreeft, 2003).

The chief condition is that "the investment must enhance competition in electricity supply". However, the *level* of competition is unclear (e.g., on one side only, on both sides of the interconnector, or overall competitiveness). Article 7.1 does not address what happens when demand elasticity is low (implying that the welfare gains from increased competition would be rather small). It is also vague about competition enhancement (e.g., increased competition may decrease regulatory costs that the regulation fails to capture, and market power that could induce excessive entry, thus incurring regulatory costs for additional monitoring). Finally, article 7.1 implicitly assumes equal social weight for consumers and producers. As Brunekreeft (2003) has argued, the positive effects of competition will be higher when weights for consumers are increased in the social welfare criterion.

In a meshed AC network, a new line (financed by interconnector-based price differences) can be privately profitable but socially detrimental due to loop-flow effects. As argued by Bushnell and Stoft (1996) and Kristiansen and Rosellón (2006), this problem could be solved by rewarding the new line with a set of must-accept incremental FTRs that will internalize such network effects. The set of incremental FTRs is determined by a central institution (TSO or ISO) using a power flow model.[5] However, Joskow and Tirole (2005) found that defining a set of incremental FTRs may internalize the network effects but could also indicate a step away from the invisible hand.

Using incremental FTRs requires an underlying system of locational marginal prices (LMP), which Europe has not yet implemented. Along with Brunekreeft (2003), we believe that this could justify allowing merchant transmission to DC interconnectors of different systems. We also assert that because Europe already employs an extensive system of zonal-pricing, it might possibly be considered as a simplified version of nodal pricing. Examples are Norway and Italy which have several internal price areas, and the majority of European countries which apply a single internal price. Zonal pricing has both favorable attributes ('simplification' of physical transmission contracts, and pragmatic rather than theoretically perfect and fewer prices in zones or nodes) that will increase liquidity in the current spot and forward markets (integration when there is no congestion), and unfavorable ones (a sub-optimal social welfare solution because it is an inaccurate representation of loop flows, i.e. unable to fully internalize all network effects since the network is modeled in a simplified manner, a trade-off between the use of capacity for internal and international transmission, and more difficulties in locating the most- and least-congested areas, and in supporting local investments). To the extent that the network effects can be localized deep connection charging (e.g., network upgrades) can internalize the network effects. Moreover, an interconnector may be compared to a new power plant that also causes network effects.

Several experts have compared European electricity transmission investment to date with the EC's recent proposals to support the development of efficient infrastructure. Hakvoort and De Jong (2007) mention the necessity of a regional assessment to select the optimal projects from a social perspective. This process requires strong cooperation between the TSOs and the regulatory authorities. Incentives for private investors may deviate from common public interests which may lead to lock-in effects and long-term inefficiencies (Hakvoort and De Jong, 2007). We emphasize the importance of transparency in undertaking all regulatory approvals of new interconnections. Allowing private investment has not yet resulted in significant increases in transmission investment projects. So far, the only identifiable merchant transmission project is the new 150 kV

[5] As discussed in ETSO (2006), TSOs should play an important role in the design and operation of FTR auctions. For instance, TSOs should define the types and duration of FTRs to be auctioned, ensure the technical simultaneous feasibility and revenue adequacy of the system, and implement a payback procedure for negative externalities generated by the transmission expansion projects (Kristiansen and Rosellón, 2006). Then the goal of the TSO is to reach a balance in the trade-off between market facilitation and risk-sharing among parties so that sound price signals are sent to all market participants.

Campocologno-Tirano (Argus, 2008), an interconnector linking Italy with Switzerland that will be operational in 2009.

Likewise, public merchant investment might be another alternative. Its impact on the economic welfare in a certain country mainly depends on institutional, political, social and even historical factors. Therefore, an “optimal” percentage of public merchant investment would be difficult to determine. It would be particular to each institutional national framework. In a multinational framework, the ideal public merchant investment would be even more difficult to determine.

5. Modeling FTRs in Europe

Financial transmission rights (FTRs) are complementary to locational marginal pricing of energy (Hogan, 1992). The objective of the FTR mechanism is to hedge locational risk associated with the spot and forward contracts. Basically, an FTR is a point-to-point financial instrument that gives its owner a financial insurance against the congestion charge in the day-ahead market for energy related to a particular energy transaction. The basic parameters defining an FTR are a source, a sink, a duration period and a MW amount. Each FTR is assigned a monetary value for each hour depending upon the day-ahead LMP outcomes for that hour, and the FTR owners are paid by the independent system operator according to the hourly values of their FTRs. Whatever may be the day-ahead locational prices, the hourly value of an obligation FTR is always given by the product of its MW amount and the LMP difference between its sink and source locations. Therefore, the obligation FTR incurs a negative value if the congestion occurs in the reverse direction. The option version of FTRs was introduced to take away the down-side risk. When the congestion occurs in the forward direction, the value of an option FTR is given by the product of its MW amount and the LMP differential on its path. However, if the direction of congestion gets reversed, the option FTR becomes inactive or its value becomes zero. Consequently, the option version provides the flexibility to get hedged for a range of transactions but at a higher price than for obligations.

The introduction of FTRs in Europe is still in its planning phase (except for Italy), and there is no concrete timetable. However it is likely that when the major European countries are coupled in implicit auctions, there will be a demand for such products. During 2004 and 2005, there was increased interest in transmission risk hedging products for cross-border trade and congestion management on several occasions. The 11th Florence Regulatory Forum discussed FTRs as a complement to auctions of forward physical transmission rights. Similarly, in October 2004, regulators CNE (Spain) and CRE (France) included financial instruments in their final public consultation concerning the implementation of coordinated and market-based congestion management mechanisms. The first example of FTRs in Europe was the introduction of FTRs by Italy’s Terna (the grid company) for zone-to-zone price volatility in January 1, 2005. The FTRs were complemented by an implicit auction scheme considering virtual zones for offers/bids from neighboring countries on the Italian side of the interconnection capacity.

Additionally, there was a focus on the appearance of new risks as TSOs adapt the existing complex physical power system to the new market with increasing number of implicit auctions. This could include potential FTR auctions where the TSOs would be the issuers of FTRs. Thus they would have to carry the counterparty risk and any shortfalls in revenue from congestion management. An efficient implementation of forward transmission rights under meshed network conditions requires TSOs to provide a more elaborate, flow-based transmission model. A simultaneous feasibility test would maximize the value of the set of FTRs accepted under constraints of zonal PTDFs and transmission capacities. RTE et al. (2006) foresees a possible future introduction of FTRs. RTE also suggests that FTRs should be introduced under regulatory control and as demanded by the market. Likewise, appropriate risk-sharing and regulatory incentives are needed

FTRs could assume several forms in Europe (APX, 2007):

- Market players could return capacity to the TSO for re-auctioning. The auction revenue they would receive could equal the market coupling price difference, or
- A use-it or sell-it principle: the market players could schedule physically, or submit for financial revenue, or
- An implicit auction in which daily financial settlement would equal that of an explicit auction, or
- Use of physical transmission capacity as an FTR, or
- Re-trading FTRs.

In this paper we apply our model for transmission expansion (Kristiansen and Rosellón 2006) to study the optimal allocation of FTRs in the TLC arrangement when the system operator reserves some FTRs (proxy awards) to resolve the negative externalities associated with transmission expansion projects.

The main assumptions for the auctioning of incremental long-term are:

(1) An FTR increment must keep being simultaneously feasible (feasibility rule).

(2) An FTR increment remains simultaneously feasible given that certain currently unallocated rights (or proxy awards) are preserved.

(3) Investors should maximize their objective function (maximum value).

(4) The LTFTR awarding process should apply both for decreases and increases in the grid capacity (symmetry).

In this model, loop flows imply that certain transmission investments might have negative externalities on the capacity of other (perhaps distant) transmission links. Moreover, the addition of new transmission capacity can sometimes paradoxically decrease the total capacity of the network. The method deals with loop-flow externalities in that, to proceed with line expansions, the investor pays for the negative externalities it generates. To restore feasibility, the investor has to buy back sufficient transmission rights from those who hold them initially, or the system operator retains some unallocated transmission rights (proxy awards) during the long-term FTR auction to protect unassigned rights while simultaneous feasibility of the system protects the rights of the existing FTR holders. This is the core of a long-term FTR auction (see Hogan, 2002 a, Kristiansen and Rosellón; 2006, and Bushnell and Stoft, 1997). Simultaneous feasibility in the model is shown to crucially depend on the investor-preference and the proxy-preference parameters. Likewise, for a given amount of pre-existing FTRs the larger the current capacity the greater the need to reserve some FTRs for possible negative externalities generated by the expansion changes.

Proxy awards take place whenever there is less than full allocation of the capacity of the existing grid. This occurs prominently during a transition to an electricity market when there is reluctance to fully allocate the existing grid for all future periods. Hence FTRs for the existing grid are short term (this period), but investors in grid expansion seek long term rights (next period). Full allocation of the existing grid seems necessary but not sufficient for defining and measuring incremental capacity. The proxy awards are transmission congestion hedges that can be auctioned to electricity market players in the expanded network.[6]

We assume a DC network for simplicity but the model can be extended to an AC network. Most of the European transmission system is AC but cables are typically DC networks. However, available transmission capacity is calculated by only considering bilateral transactions and not their simultaneous interaction in the entire network.

The topology is shown in Figure 2.

[6] When there are institutional restrictions to issuing LTFTRs, there will be an additional (expected congestion) constraint to the model. A proxy for the shadow price of such a constraint would be reflected by the preferences of the investor carrying out the expansion project (assuming risk neutrality and a price-taking behavior). The proxy award model takes the "linear" incremental and proxy FTR trajectories to the after-expansion equilibrium point in the ex-post FTR feasible set to ensure the minimum shadow value of the constraints.

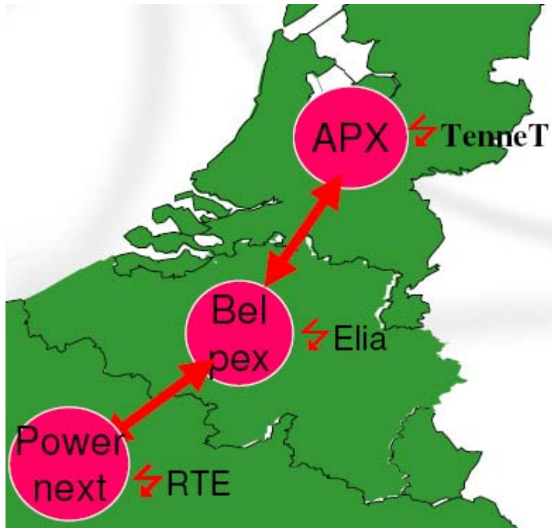

Figure 2. The topology of the TLC arrangement.

The NTCs among the TLC countries in 2007 are shown in Table 4. These indicate the capacity made available to market participants for trading. Generally speaking, there is more capacity available from France to Belgium and from Belgium to the Netherlands. France is typically a net exporter of electricity in the summer season and importer in the winter season because of its higher dependence of electricity for heating. However, the physical transmission capacity for the same interconnectors *differs* from the trading capacity due to the definition of NTC that only considers the commercial bilateral exchange (see appendix).[7]

NTC (forward/backward)	Summer 2007 (MW)	Winter 2006-2007 (MW)
Netherlands-Belgium	1900/2000	2400/2400
Belgium-France	1100/2700	1100/3200

Table 4. NTCs among the TLC countries.

[7] Leuthold and Todem (2007) show that the differences between the calculated NTCs and flows can be substantial in a three-node network. For example, if one interconnector has auctioned NTC = 100 MW and the other has auctioned zero, the real flow will be 66.7 MW in the first interconnector and 33.3 MW in the others, although the auctioned NTC is zero. A flow-based allocation method can lead to higher border capacity (BC) values than NTC values for the same border, and real flows are more representative in a flow-based auction. .

Based on current price levels the most profitable investment appears to be between France and the Netherlands. However these countries do not have any border and such an investment thus not appear likely except in the case of a sub-sea cable.[8] To increase capacity towards the Netherlands, the capacity from France to Belgium or from Belgium to the Netherlands can be expanded further. We can analyze the France-Belgium (index FB) case (the other case would be similar) using our model, with the Lagrange multipliers associated with each constraint indicated within the brackets of the following problem formulation:

$$\begin{aligned}
&\underset{a,\hat{t},\delta}{Max}\; a(b_{FB}\delta_{FB}) \\
&\text{s.t.} \\
&T_{FB} + a\delta_{FB} \le C^{+}_{FB} \quad (\omega) \\
&T_{FB} + (\hat{t} + a)\delta_{FB} \le C^{+}_{FB} \quad (\gamma) \\
&\hat{t} \in \arg\max_{t} \{t(p_{FB}\delta_{FB})\} \\
&T_{FB} + \hat{t}\delta_{FB} \le C_{FB} \quad (\lambda) \\
&\delta^{2}_{FB} = 1 \quad (\varphi) \\
&a \ge 0 \quad (\kappa)
\end{aligned} \tag{1}$$

where

a scalar amount of incremental FTRs

b bid preference parameter of the investor

C vector of transmission line capacities

C^{+} vector of transmission line capacities in the expanded network

p vector of the preset proxy preference prices

t scalar amount of unallocated (or proxy) FTRs

$\hat{t}$ optimal scalar amount of unallocated (or proxy) FTRs

T current partial allocation of FTRs

δ directional vector (where each element represents an FTR between two locations, the vector may have many elements representing combinations of FTRs).

The application of our model provides the following results. The first constraint on simultaneous feasibility of incremental FTRs $T_{FB} + a\delta_{FB} \le C^{+}_{FB}$ is non-binding, because the

[8] The problem of the optimal choice of a specific expansion project is beyond the scope of this paper. Such a choice would depend on criteria related to technical engineering, economic profit, distribution and welfare (and even political) factors (more on welfare effects is discussed in section 6). The transmission expansion chosen (France-Belgium) is intuitively done since the most profitable investment would occur in that project.

grid is being expanded. The solution to this problem gives $\delta_{FB} = 1$, because the network is being expanded. Additionally $\gamma = b_{FB}$ implies that the higher the value of the investor-preference parameter b_{FB}, the more the investor values post-expansion transmission capacity (its marginal valuation of transmission capacity increases with the bid value). Similarly, we find $\lambda = p_{FB}$ which implies that the higher the value of the preset proxy preference parameter p_{FB}, the higher the marginal valuation of pre-expansion transmission capacity.[9]

We can also expect that $\varphi = 0$ because the expansion factor δ is non-zero. Furthermore, $\hat{t} = C_{FB} - T_{FB}$, meaning that for given existing rights, the higher the current capacity the larger the need for reserving some FTRs for possible negative externalities generated by the expansion. Finally, $a = C^{+}_{FB} - T_{FB} - \hat{t} = C^{+}_{FB} - C_{FB}$ shows that the optimal amount of additional MWs of FTRs in direction δ depends directly on the amount of capacity expansion. Thus the investor receives incremental FTRs for the incremental capacity in which it has invested. If there are no existing FTRs, T_{FB} (the amount of proxy FTRs) equals the capacity of the interconnector before the expansion C_{FB}.

We note that when an interconnector is invested in routed parallel to the existing link our model will give the identical solution as above. Both the proxy and incremental FTRs exhaust transmission capacity in the pre-expansion and expanded grid, respectively. The proxy FTRs assist in allocating incremental FTRs by preserving capacity in the pre-expansion network, resulting in an allocation of incremental FTRs that equals the new transmission capacity created in the France-Belgium direction.[10]

The auction problem becomes more complex when any third interconnector is linked to the TLC arrangement (making it a triangular three-node network), such as investing in an undersea cable from France to the Netherlands without crossing Belgium.[11] For example, the NorNed cable that became operational in May 2008 now links the TLC countries with Nord Pool, adding another radial link to the TLC arrangement. The next possible expansion of the TLC might be a market coupling to Germany. Since Germany is expected to have an implicit auction with Denmark, the TLC market could become fully integrated with Nord Pool and Germany resulting in an even larger (and more liquid) geographical area.[12] Our intention here is to illustrate the main features of the model. We

---

[9] We have omitted some calculations of Lagrange multipliers. These are $\theta = 0$, $\zeta = \gamma / p_{32} = b_{32} / p_{32}$ and ε = 0Rosellón. This was expected since only one restriction for the lower problem is binding because the other two are redundant. The value of the binding Lagrange multiplier equals the ratio between the investor's bid value, and the preset proxy parameter.

[10] Note that this result will depend on the network interactions. In some cases, the amount of incremental FTRs in the preference direction will differ from the new capacity created on a specific line. However, it will always amount to the new capacity created as defined by the scalar amount of incremental FTRs times the directional vector.

[11] The implemented model is radial 3-node but we discuss the impact of introducing another link so the network becomes a 3-node 3 link network. Even if the network is radial there can still be externalities associated with the investment.

[12] Kristiansen and Rosellón (2006) also analyze the impact of PTDFs on allocation of FTRs. This introduces other practical issues in the implementation of FTRS. For instance, examples of projects that do not change PTDFs include appropriate maintenance and upgrades (e.g. low sag wires), and the capacity expansion of a radial line

refer to Kristiansen and Rosellón (2006) for how to solve the three-node topology. More advanced network topologies would require numerical solutions.

A cross-border with a high volume of congestion hedges (proxy awards), should give lower amount of awards to the investor but the value to the investor still may be high if the country price differential is large. Furthermore it can be argued that TLC market coupling arrangement is already part of the interconnected European power system and thus is prone to loop flows, and thus there is a need for proxy awards to take care of the negative externalities.

6. Welfare analysis

Bushnell and Stoft (1997) analyzed the welfare implications of transmission expansion when dispatch matches both individually and in the aggregate. They show that under such conditions, social welfare is not reduced by an expansion of the transmission network. Kristiansen and Rosellón (2006) assumed unallocated FTRs both before and after the expansion, so that there is no match in dispatch. Their proxy award mechanism implies nonnegative effects on welfare of aggregate use for *FTR holders only,* since simultaneous feasibility and revenue adequacy are guaranteed before and after an expansion. However, since non-hedged agents in the spot market will be exposed to rent transfers, FTRs cannot provide perfect hedges ex post for all possible hedged and non-hedged transactions.

The merchant model used for the TLC arrangement in this paper should also meet the above conditions. To validate this, we assume a social welfare function B for dispatch in a single period in the following welfare maximization:

$$\underset{\Delta}{Max}\, B(Y^* + \Delta) \qquad (2)$$

s.t.

$$K^+(Y^* + \Delta) \leq 0$$

where

$$Y^* \in \arg\max\{B(Y) | K(Y) \leq 0\}$$

Y^* is dispatch that maximizes social welfare without the expansion. Let Δ^+ be the dispatch that would be provided as an increment due to transmission expansion. Δ^+ solves this program.

If $P^+ = \nabla B(Y^* + \Delta^+)$, then under reasonable regularity conditions Δ^+ is a solution to:

$$\underset{\Delta}{Max}\, P^+ \Delta \qquad (3)$$

s.t.

$K^{+}(Y^{*}+\Delta)\leq 0$

This is interpreted as the maximization of congestion rents for the incremental allocation Δ. If the current allocation of FTRs T satisfy $T=Y^{*}$, this program would provide the maximum value of incremental FTRs for expansion K^{+}, and this award would preserve the welfare maximizing property of the FTRs for the expanded grid.

Now suppose that $T\neq Y^{*}$. A "second best" rule is:

$$\underset{\Delta}{Max}\, P^{+}\Delta$$

$s.t.$

$$K^{+}(Y^{*}+\Delta)\leq 0$$

(4)

$$K^{+}(T+\Delta)\leq 0$$

$$Y^{*}\in \arg\max\{B(Y)|K(Y)\leq 0\}$$

Hence, the existing users of the grid could continue as before expansion, and the expander receives the incremental values resulting from the expansion. It can be shown that for certain expansion projects and topologies the only solution is $\Delta=0$ so that the expansion project does not occur.

We tested this last argument for the expansion cases we propose for the TLC coupling arrangement. Consider again the case of expansion of the TLC arrangement with capacity between France and Belgium. The relevant constraints are:

$$T_{FB}+\Delta_{FB}\leq C_{FB}^{+}$$

$$Y_{FB}+\Delta_{FB}\leq C_{FB}^{+} \qquad (5)$$

Assuming that $C_{FB}=3500, C_{FB}^{+}=4000, T_{FB}=3000,$ and $Y_{FB}=3500$, note the mismatch between the dispatch and existing FTRs of $Y_{FB}-T_{FB}=500$. The marginal dispatch corresponds to $\Delta_{FB}=500$. Substituting these numbers in the above constraints gives $Y_{FB}+\Delta_{FB}=3500+500=4000$ and violates the constraints. Hence, the expansion occurs. Now let us interchange the dispatch and amount of existing FTRs to $Y_{FB}=3000,$ and $T_{FB}=3500$. The marginal dispatch corresponds to 1000 and violates the constraint $T_{FB}+\Delta_{FB}=3500+1000=4500>4000$. Hence, the expansion does not occur.

7. Conclusions

In this paper we discussed the introduction of FTRs to the TLC border arrangement among the Netherlands, Belgium and France. Our aim has been to hint the benefits that the introduction of long-term FTRs in transmission expansion projects would have for investors and for social welfare in future European transmission networks. Transmission investment projects based on FTRs are implementable, and can provide hedging benefits to market players. The TLC has already proven to grant several benefits such as optimal use of cross-border transmission capacity, increased liquidity, and price stability and convergence. A similar mechanism is planned through expanded interconnections between Germany and the Netherlands, Norway and the Netherlands, as well as the UK and the Netherlands. The potential introduction of FTRs to the TLC is one aspect of the interest for hedging products for cross-border trade and congestion management by several regulatory bodies observed at both continental and national levels (e.g., Spain, France, and Italy). The efficient implementation of FTRs in meshed networks would however require that Europe's TSOs handle flow-based transmission models that achieve simultaneous feasibility as well as revenue adequacy within an incentive regulatory framework.

We simulated a model of optimal allocation of FTRs for an interconnector between France and Belgium when the system operator reserves some proxy FTR awards that resolve the negative externalities derived from transmission expansion. We showed the feasibility of such a project under our proposed FTR auction system, and corroborated several analytical results, such as the direct relationships between the post expansion capacity and the bid value of the investor's preference parameter, the current capacity and proxy FTRs, and the amount of capacity expansion and incremental FTRs. By awarding long-term FTRs, investors in transmission get an incentive to undertake projects that might not be undertaken otherwise. As such, it serves as a mechanism to stimulate new investments. Notwithstanding, positive welfare impacts can only be guaranteed for FTR holders. Although reduced, this still suggests the complementary need of regulatory oversight.

The likelihood of other projects may also be addressed using our model. For instance, an interconnector that invests in a route parallel to an existing line, or a third interconnector that links to the TLC arrangement, thus forming a three-node network (such as an undersea cable from France to the Netherlands, or the links with Nord Pool or Germany). Although in many cases only local optima for an FTR auction may be achieved, FTR-supported expansion projects in Europe are technically and financially feasible. All of our analyses suggested that employing FTRs in TLC arrangements would require daily settlements in implicit auctions between power exchanges, clear definitions of the roles of TSOs and power exchanges (including training and procedural simplification), as well as the identification and provision of appropriate risk-sharing and regulatory incentives.

References

APX (2007), homepage: www.apxgroup.com.

Argus (2008). Argus European Electricity, Monday 28 April 2008.

Brunekreeft, G. (2003), "Regulatory issues in merchant transmission investment," Utilities Policy.

Bushnell, J. B. and S. E. Stoft (1996), "Electric Grid Investment Under a Contract Network Regime," *Journal of Regulatory Economics* 10, 61-79.

Bushnell, J. B. and S. E. Stoft (1997). "Improving Private Incentives for Electric Grid Investment," *Resource and Energy Economics* 19, 85-108.

CONSENTEC GmbH, Aachen and APCS AG, Vienna (2008). "Dry Run of Coordinated Flow Based Capacity Allocation in SEE –Latest Developments", presentation at joint meeting of SETSO NACMPF SG, Balance Management SG and EFETTF SEE, Vienna, 26 March 2008

ETSO (2004), "Transfer capacity definitions," June.

ETSO (2007), "Regional flow-based allocations – State of play, final paper," March.

ETSO (2006), "Transmission Risk Hedging Products. Solutions for the Market and Consequences for the TSOs," Background Paper, February.

Hakvoort R. A and H. M. De Jong (2007). Pushing European power transmission: Private investment in priority interconnections? European Review of Energy Markets, "Regulatory and technical challenges for the European electricity and has transmission system" 2(1): 109-139.

Hogan, W. (1992), "Contract Networks for Electric Power Transmission," *Journal of Regulatory Economics* 4, 211-242.

Hogan, W. (2000). "Flowgate rights and wrongs," handout, JFK School of Government, Harvard Electricity Policy Group, Harvard University, http://www.ksg.harvard.edu/people/whogan.

Hogan, W. (2002a), "Financial Transmission Right Incentives: Applications Beyond Hedging," Presentation to HEPG Twenty-Eighth Plenary Session, May 31, http://www.ksg.harvard.edu/people/whogan.

Hogan, W. (2002b), "Financial Transmission Right Formulations. Handout," JFK School of Government, Harvard Electricity Policy Group, Harvard University, http://www.ksg.harvard.edu/people/whogan.

Joskow, P. and J. Tirole (2005). "Merchant Transmission Investment,".*Journal of Industrial Economics*, Blackwell Publishing, vol. 53(2), pages 233-264, 06.

Kristiansen T. and J. Rosellón (2006), "A Merchant Mechanism for Electricity Transmission Expansion," *Journal of Regulatory Economics* 29, Number 2, pp. 167-194, March.

Kristiansen T. (2004). “Markets for financial transmission rights,” [Online]. Available:
http://www.ksg.harvard.edu/hepg/Papers/Kristiansen.mkts.for.ftrs.Oct.03.updated.May.04.pdf

Kristiansen T. (2007), “Allocation of long-term financial transmission rights for transmission expansion,” *European Journal of Operational Research*, forthcoming.

Leuthold F. and C. Todem (2007), “Flow-Based Coordinated Explicit Auctions: Auction Income Distribution,” working paper.

O’Neill, R.P., U. Helman, B.F. Hobbs, W.R. Stewart, and M.H. Rothkopf (2002). “A Joint Energy and Transmission Rights Auction: Proposal and Properties,” IEEE Trans. Power Systems, 17(4), November, 1058-1067.

Philpott, A. and G. Pritchard. (2004), “Financial transmission rights in convex pool markets,” Operations Research Letters, Volume 32, Issue 2, March, 109-110?.

Powernext (2008). Balancing GRT Gaz 2007 Market Activity.

RTE, ELIA and Tennet (2006), “Management of interconnection capacities, presentation,” January.

Wood, A. J. and B. F. Wollenberg (1996), “Power Generation, Operation and Control,” John Wiley & Sons, New York.

Appendix

Transmission capacity definitions (ETSO, 2004)

1. Total transfer capacity (TTC) is the maximum exchange program between two areas subject to security standards at each power system under perfect foresight of network conditions, generation and load patterns.

2. Transmission reliability margin (TRM) is a security margin that incorporates uncertainties about the calculated TTC values.

3. Net transfer capacity (NTC), defined as NTC= TTC – TRM, is the maximum exchange program between two areas compatible with security standards applicable in both and accounting for the technical uncertainties of the future network.

4. Already allocated capacity (AAC) is the total amount of allocated transmission rights including capacity or exchange programs.

5. Available transmission capacity (ATC), defined as ATC = NTC –AAC, is the portion of NTC that remains available after each phase of the allocation procedure for additional commercial activity.